NSTAR

Commonwealth of Massachusetts Department of Telecommunications and Energy

D.T.E. 05-88

Boston Edison Company

2005 Reconciliation of Transition Charge Transmission Charge Standard Offer Costs Default Service Costs

December 2, 2005

NSTAR ELECTRIC 800 Boylston Street, SUM NE 240, Boston, Massachusetts 02199

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December 2, 2005

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station, 2nd Floor
Boston, Massachusetts 02110

Re: D.T.E. 05-88, Boston Edison Company – 2005 Reconciliation Filing

Dear Secretary Cottrell:

Boston Edison Company, d/b/a NSTAR Electric ("Boston Edison" or the "Company") hereby submits an original and nine (9) copies of its 2005 Transition Cost Reconciliation Filing (the "Filing"). The Filing is being made in accordance with the requirements of G.L. c. 164, § 1A(a), 220 C.M.R. 11.03(4)(e) and the Restructuring Settlement, as approved by the Department of Telecommunications and Energy (the "Department") in Boston Edison Company, D.P.U./D.T.E. 96-23 (1998).

Included with the Filing is a reconciliation of 2005 Transition, Transmission, Standard Offer and Default Service costs and revenues along with proposed updated charges and tariffs to be effective January 1, 2006. In order to comply with statutory rate reduction requirements and the Department's rate design directives, there are minor adjustments to distribution rates in some rate schedules. The primary changes in rates included with this filing are reflected in the following table:

BOSTON EDISON COMPANY	2005 ($ per kWh)	2006 ($ per kWh)
Transition Charge	$0.02012 (ave.)	$0.01916
Transmission Charge	$0.00580	$0.01312
Default Service Adjustment	$0.00000	$0.00065

This filing substantially follows the methodology set forth in the Company's previous annual true-up filing in D.T.E. 04-113.

Consistent with previous reconciliation filings, this filing includes part-actual/part-forecast data for 2005. As with last year's filing, the Company proposes to update this filing in the spring of 2006, to provide year-end data and to allow a final reconciliation for 2005.

In accordance with the Restructuring Settlement and applicable provisions of the Electric Restructuring Act, Boston Edison requests approval of the tariffs set forth in Attachment A, effective January 1, 2006.

In support of the Company's Transition Charge Reconciliation Filing, and the accompanying proposed tariff changes, Boston Edison has enclosed the prefiled testimony and exhibits of Christine L. Vaughan and Henry C. LaMontagne. Ms. Vaughan's testimony provides a description of the methodology used by Company to reconcile the forecast of Transition Charge revenues and costs, as well as Transmission, Standard Offer and Default Service costs and revenues. Mr. LaMontagne's testimony describes the proposed rate changes, how the reconciled Transition Charge will be implemented and what its impact will be on customers' bills. Mr. LaMontagne also provides an exhibit showing the proposed tariff changes in redlined format showing changes from current tariffs.

Any correspondence with regard to this filing should be directed to the following:

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Thank you for your attention to this matter.

Sincerely,

Robert N. Werlin

Enclosures

cc: Shaela Collins, Hearing Officer
Service List, D.T.E. 04-113

Attachment A

Proposed Tariffs

M.D.T.E. No.	Boston Edison Company Rate Schedule
120E	Residential Rate R-1
121E	Residential Assistance Rate R-2
122E	Residential Space Heating Rate R-3
123E	Optional Residential Time-of-Use Rate R-4
130E	General Service Rate G-1
131E	General Service Rate G-2
132E	General Service Time-of-Use Rate G-3
133E	Optional General Service Time-of-Use Rate T-1
134E	Time-of-Use Rate T-2
135E	MWRA Rate WR
140E	Streetlighting Rate S-1
141E	Streetlighting Energy Rate S-2
142E	Outdoor Lighting Rate S-3
104D	Default Service Adjustment

BOSTON EDISON COMPANY

D/B/A NSTAR ELECTRIC

Direct Testimony of Christine L. Vaughan

Exhibit BEC-CLV

D.T.E. 05-88

BOSTON EDISON COMPANY
d/b/a NSTAR ELECTRIC

Direct Testimony of Christine L. Vaughan

Exhibit BEC-CLV

D.T.E. 05-88

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Christine L. Vaughan. My business address is 1 NSTAR Way, Westwood, MA 02090.

Q. By whom are you employed and in what capacity?

A. I am Manager of Regulatory Requirements for the regulated operating companies of NSTAR. In this capacity, I am responsible for all regulatory filings concerning the financial requirements of Boston Edison Company ("Boston Edison" or the "Company"), Cambridge Electric Light Company ("Cambridge"), Commonwealth Electric Company ("Commonwealth") and NSTAR Gas Company (together, "NSTAR").

Q. Please summarize your educational background.

A. I graduated from McGill University in Montreal, Canada in 1990 with a Bachelor of Engineering Degree and from Yale University in New Haven, CT in 1998 with a Masters Degree in Business Administration. Additionally, I have earned the right to use the Chartered Financial Analyst designation.

Q. Please describe your current responsibilities.

A. I was hired as Manager of Regulatory Requirements on July 19, 2004. In this role, I am responsible for directing the preparation of financial data required for rate case filings and serve as the revenue requirement witness. My responsibilities include, among a variety of other financial services, the reconciliation of Boston Edison's Transition Charge that forms the basis of my testimony today.

Q. Please summarize your previous business experience.

A. I worked as a management consultant for five years at Arthur D. Little and at Charles River Associates, a company that purchased a portion of Arthur D. Little. In this capacity, I assisted clients with financial issues such as acquisition support and asset privatization. I also helped clients develop long-range strategic plans and assisted them with market analysis. Prior to my consulting experience and my MBA, I worked for six years at DuPont and BASF as a development engineer.

Q. Have you previously testified before any regulatory body?

A. Yes. I have sponsored testimony in D.T.E. 04-113, Boston Edison's 2004 Annual Reconciliation Filing, and for NSTAR's Pension Adjustment Factor in D.T.E. 04-118. Also, I have sponsored testimony in D.T.E. 04-114, the 2004 Annual Reconciliation Filing for Cambridge Electric Light Company and Commonwealth Electric Company, and D.T.E. 04-65, Cambridge's filing regarding the valuation of streetlights. I offered testimony at the Federal Energy Regulatory Commission (the "FERC") in Docket No. ER05-69-000 on behalf of Boston Edison relating to the modification of the Company's FERC Tariff No. 8, chiefly to permit the inclusion of 50 percent of construction work in progress in rate base. I am also concurrently sponsoring testimony in D.T.E. 05-89, the reconciliation filing of Cambridge and Commonwealth.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony addresses the reconciliation filing for Boston Edison. Its purpose is to provide support for the Company's request for approval of the proposed Transition Charge, Retail Transmission, and Default Service Adjustment rates to become effective January 1, 2006. My testimony also requests approval of the 2005 preliminary reconciliation of Transition Charge, Retail Transmission, Standard Offer Service, and Default ("Basic") Service expenses and revenues and presents an estimate of such expenses and revenues for 2006. Further, I will describe the Company's efforts to mitigate its transition costs to the maximum extent possible, consistent with the Act and the Boston Edison Company Restructuring Settlement Agreement ("Restructuring Settlement") approved by the Department in D.P.U./D.T.E. 96-23. Finally, I will describe how NSTAR Electric procures Basic Service for Boston Edison customers and NSTAR Electric's proposal for continued procurement during the year 2006.

Q. Please explain the requirement for Transition Charge Reconciliation.

A. Section 1A(a) of the Act requires the Department to review and to reconcile the difference between projected transition costs and actual transition costs periodically.

Boston Edison's Restructuring Settlement, as approved in D.P.U./D.T.E. 96-23, requires an annual reconciliation to coincide with the implementation of new rates (Restructuring Settlement, § V.E.).

My testimony provides a description of the methodology used by the Company to reconcile the forecast of Transition Charge revenues for the period January 1, 2005 through December 31, 2005. This includes information concerning Transition Charge revenues and costs for 2005 using actual data, where available, and forecast data for the remainder of the year.

Q. Please describe the exhibits included as attachments to your testimony.

A. In addition to this testimony, Exhibit BEC-CLV, I sponsor five exhibits as follows:

Exhibit BEC-CLV-1 is an eight-page exhibit that summarizes the development of the Company's proposed Transition Charge for 2006 and the preliminary reconciliation of Transition Charge costs and revenues for the period January 1, 2005 through December 31, 2005.

Exhibit BEC-CLV-2 is an eight-page exhibit that sets forth the revenue credits and damages, costs or net recoveries from claims. This is a part of the variable component of the transition charge an the effect of these adjustments is reflected in Exhibit BEC-CLV-1, Page 4, Column F. These adjustments include costs associated with the Company's previous ownership of the Pilgrim Nuclear Power

Station ("Pilgrim"), determination of the Wholesale Revenue Credit, securitization payments , Department of Energy (DOE)/Spent Nuclear Fuel litigation expenses, and revenues collected for Standard Offer Service after February 28, 2005.

Exhibit BEC-CLV-3 is a two-page exhibit that determines the Company's proposed Transmission Charge for 2006, and sets forth the preliminary reconciliation of Transmission Charge revenues for the period January 1, 2005 through December 31, 2005.

Exhibit BEC-CLV-4 is a six-page exhibit that sets forth the reconciliation of the revenues and expenses for Standard Offer Service through February 28, 2005, the termination date of Standard Offer Service.

Exhibit BEC-CLV-5 is a two-page exhibit that sets forth the preliminary reconciliation of the revenues and expenses for Basic Service during 2005 and project the costs and revenues for Basic Service during 2006.

As with last year's filing, the Company anticipates making a supplemental filing in the Spring of 2006, once the accounting for the year 2005 has been completed and actual amounts are known. At that time, actual 2005 information will be available to reconcile 2005 Transition Charges.

III. BACKGROUND OF BOSTON EDISON'S TRANSITION CHARGE

Q. What is the purpose of the Company's Transition Charge?

A. As approved by the Department as part of Boston Edison's Restructuring Settlement, D.P.U./D.T.E. 96-23, and as set forth in the Act, the Transition Charge recovers the above-market costs of generation-related investments and obligations that electric companies have undertaken to provide service to their customers under traditional utility regulation. The Act authorizes and directs the Department to allow any approved transition costs to be recovered from customers through a non-bypassable Transition Charge collected by the distribution company providing service to such customers. G.L. c. 164, § 1G(e).

Q. What is the history of Boston Edison's Transition Charge?

A. With Department approval, the Company has instituted the following transition charges on the dates indicated.

Effective Date	**Transition Charge** (per kilowatt-hour ("kWh")
March 1, 1998	$0.03510
June 1, 1998	$0.03030
January 1, 1999	$0.02760
September 1, 1999	$0.02546
January 1, 2000	$0.01891
January 1, 2001	$0.01397
January 1, 2002	$0.01628
January 1, 2003	$0.01840
January 1, 2004	$0.01870
January 1, 2005	$0.02335
July 1, 2005	$0.01634

Q. What is the Company's proposed Transition Charge for the year 2006?

A. The proposed average Transition Charge is $0.01916 per kWh. This charge is to become effective on January 1, 2006.

Q. Are there any notable differences between the methodology used to compute the proposed Transition Charge for 2006 and the methodology that was used in prior years?

A. The basic methodology continues to follow very closely the methodology employed in last year's reconciliation filing. However, a new cost item, "the Securitization Payments from the Buyout of Purchased Power Contracts", has been included in the transition charge for Boston Edison and will be discussed later in the testimony.

IV. CALCULATION OF THE PROPOSED TRANSITION CHARGE

Q. Please describe the categories of transition costs.

A. The Company's transition costs consist primarily of two components: (1) a Fixed Component and (2) a Variable Component. The Fixed Component includes the principal and interest payments for the securitized unrecovered net book value of Boston Edison's generation plant and generation-related regulatory assets, net of the proceeds from the divestiture of generating facilities, as specified in the Act. The Variable Component primarily includes above-market purchased-power contract costs, payments in lieu of taxes, wholesale credits, miscellaneous costs and net recoveries from claims, Securitization Payments from the Buyout of Purchased Power Contracts and a rate design adjustment. I say "primarily" because there are also two other elements of cost, the Transition Charge Mitigation Incentive and interest on the prior year's over (or under) collected balance, that are recovered through the Transition Charge, but that are not clearly assigned to either the Fixed or the Variable Component.

Q. How did the Company develop its proposed Transition Charge to become effective on January 1, 2006?

A. The proposed 2006 Transition Charge is developed in Exhibits BEC-CLV-1 and is supported by BEC-CLV-2, which includes updated amounts for the Variable Component of the Transition Charge. I should note that the starting point, which is the amount of over-collection for the year 2004 for Boston Edison, is taken directly from Exhibit BEC-CLV-1 (Supp) for D.T.E. 04-113 that was filed on February 24, 2005. The Transition Charge expenses to be recovered in 2006 and after (Exhibit BEC-CLV-1, Page 1, Column J) are divided by the forecast of 2006 kWh retail billed sales in Column B to arrive at the nominal Transition Charge rate shown in Column C.

EXHIBIT BEC-CLV-1

Q. Please describe the Exhibit BEC-CLV-1.

A. Exhibit BEC-CLV-1 represents the update to the Transition Charge and is made up of the following pages:

Page	Description
1	Transition Charge Calculation for 2006
2	Estimated 2005 Transition Revenues

3 Fixed Component
4 Variable Component
5 Mitigation Incentive Calculation
6 Purchased Power Total Obligation Detail
7 Purchased Power Market Value Detail
8 Purchased Power Above Market Cost Detail

Q. Please explain Page 1, the Transition Charge Calculation for 2006.

A. Page 1 is a summary page that compares delivered Transition Charge revenues to actual transition costs to arrive at the annual over- or under-collection for each year. This page begins with the year-end balance for 2004 reflecting the outcome of last year's activity, preliminary data for 2005 (with eight months of actual and four months of forecasted data), and projected data for 2006 and thereafter. Column B shows the actual and forecast gigawatt-hours ("GWh") billed for each calendar year. The forecast for 2006 reflects the Company's internal projection of sales. Subsequent years use the 2006 sales forecast, increased by 2 percent per year.

For the year 2006 and after, Column C is calculated by dividing Column J (total expenses) by Column B. The Transition Charge revenues for delivered GWh (Column D) show the forecast Transition Charge revenues for 2005, as calculated on Page 2. For years subsequent to 2005, Column D is the same as Column J, reflecting the Company's intention that the Transition Charge is set at the level such that projected revenues match projected expenses. Transition Charge expenses, or transition costs, are shown in Columns E through I. The total Fixed

Component (Column E) is shown on Page 3. The total Variable Component (Column F) is calculated on Page 4. The Incentive Mechanism (Column G) is calculated on Page 5. To these current-year expenses, an adjustment is made for the prior year over- or under-collection (Column H), including carrying charges (Column I) at 10.88 percent, the rate approved by the Department in the Company's Restructuring Settlement.

The amounts shown on Page 1, Columns E through I, are summed, representing the total current year actual transition expense, as shown in Column J. Column K compares the revenues in Column D to the expenses in Column J to arrive at the balance of over- or under-collections for the current year. References for each of the columns can be found at the foot of the page.

Q. Please explain Page 2, Estimated 2005 Transition Revenues.

A. The 2005 billed revenues reflect eight months of actual revenue taken from the Company's general ledger and four months of estimated revenue from the Company's current forecast. The commercial Transition Charge revenues include the WR rate and Special Contracts. In order to match billed revenues for 2005 with the revenues associated with kWh delivered during 2005, it is necessary to adjust for unbilled revenues for the end of 2004 with a similar, but opposite, adjustment for the end of 2005. The unbilled revenues forecast for the year-end 2005 are per the Company's general ledger in order to determine revenues for kWh delivered in 2005. The kWh delivered in 2005 are therefore the billed kWh in 2005 less the estimated unbilled kWh at the end of 2004 plus the estimated unbilled kWh at the end of 2005.

Q. Please describe Page 3, Fixed Component.

A. Page 3 of Exhibit BEC-CLV-1 shows the amount of Fixed Component obligations resulting from securitization, which was effective July 29, 1999. The total annual Fixed Component (column E) reflects the sum of amortization of principal (Column C) and the associated interest from the bonds and the administration expense associated with the securitization transaction (Column D). The total amounts are reflected in Exhibit BEC-CLV-1, page 1, Column E.

Q. Please describe Page 4, Variable Component.

A. The Variable Component is composed of three major elements: (i) above-market costs relating to pre-restructuring purchased-power contracts; (ii) revenue credits, damages and claims or net recoveries from claims; and (iii) a rate-design adjustment.

The above-market purchased-power costs, or Net Power Obligation, reflect the difference between the prices paid for electricity pursuant to pre-restructuring purchased-power contracts less the market value of the power received from those contracts. The power-contract obligations, the market value of the contracts, and the resulting above-market values are further detailed on pages 6-8 in Exhibit BEC-CLV-1. For January and February 2005, all of the power has been effectively used to supply Standard Offer Service. Therefore, the Companies determined a "transfer price" to account for the market cost of this power. The calculation of the transfer price and the source of the values for January and February 2005 are contained in Exhibit BEC-CLV-4.

The market costs after March 1, 2005 is the revenues received for selling the Company's output from the remaining purchased power contract on the open market.

Column F, Actual Revenue Credits and Damages, Costs, or Net Recoveries from Claims, includes adjustments for 2005, as set forth in more detail in Exhibit BEC-CLV-2. The adjustments consist of the following: (1) a NEIL insurance refund; (2) Maxey Flats LLC expenses; (3) payments in lieu of property taxes; (4) proceeds from sale of property; (5) wholesale revenue credit; (6) a securitization true-up for BEC Funding; (7) Department of Energy/Spent Nuclear Fuel Litigation Expense; (8) BEC Funding II Securitization Payments; and (9) Residual Standard Offer Revenues. The adjustments currently do not include estimates for the legal and consulting costs associated with the PPA buyouts and restructurings that occurred in 2004 and 2005. These will be included in the updated reconciliation filing to be submitted early next year.

The Rate Design Adjustment established under the terms of the settlement agreement in D.T.E. 00-82 provides for a class-specific Transition Charge adjustment. The calculation and implementation of this adjustment is contained in the testimony of Mr. LaMontagne. The amounts for 2006 are calculated on Exhibit BEC-HCL-7. This adjustment is not intended as an actual source of additional revenue, and because Exhibit BEC-CLV-1 sets future Transition Charges at levels intended to recover the Company's costs, it is necessary to remove the aggregate reconciliation impact of the Rate Design Adjustment in the following year. This is done in the column titled Reversal of Prior Year Rate Design Adjustment.

Q. Please explain Page 5, Transition Charge Mitigation Incentive Mechanism.

A. Pursuant to the Company's Restructuring Settlement, recovery of the Company's Transition Charge Mitigation Incentive began in 2000. The Transition Charge Mitigation Incentive, which was approved by the Department as part of the Restructuring Settlement, is a small addition to the Transition Charge to provide the Company with a monetary incentive for successful mitigation efforts that reduce the cumulative average Transition Charge below the 1998 level of $0.03510 per kWh. Exhibit BEC-CLV-1, Page 5, computes the mitigation incentive in accordance with the provisions of the Restructuring Settlement. The Transition Charge Mitigation Incentive is carried forward to page 1, column G.

Q. Please explain Page 6, Purchased Power Total Obligation Detail.

A. Page 6 provides detail supporting the total power contract obligations shown on Page 4, Column B. The detail shows the Company's forecasted costs pursuant to the remaining Purchased Power Contracts, Nuclear Decommissioning Costs and Transmission in Support of Remote Generation Costs by item.

Q. Please explain Page 7, Purchased Power Market Value Detail.

A. Page 7 provides detail supporting the total power contract market value shown on Page 4, Column C. The detail shows the Company's forecasted market value pursuant to the remaining Purchased Power Contracts, Nuclear Decommissioning Costs, Transmission in Support of Remote Generation Costs and Other Adjustments. The Other Adjustment reflects an annual transfer of savings to Boston Edison from Commonwealth over a ten-year period resulting from the restructuring of the NEA Purchased Power Contract. The Department approved the NEA Restructuring Agreement in D.T.E. 04-85 along with the allocation of savings between Boston Edison and Commonwealth.

Q. Please explain Page 8, Purchased Power Above Market Cost Detail.

A. Page 8 provides detail supporting the total power contract above-market cost shown on Page 4, Column D. The detail is calculated by subtracting the amounts shown on Page 7 from the amounts shown on Page 6. The detail shows the Company's forecasted above market costs to be recovered from customers pursuant to the Purchased Power Contracts, Nuclear Decommissioning Costs and Transmission in Support of Remote Generation Costs by item.

Exhibit BEC-CLV-2

Q. Please describe Exhibit BEC-CLV-2.

A. Exhibit BEC-CLV-2 is an eight-page schedule that summarizes the revenue credits and damages, costs or net recoveries from claims that are carried forward to Exhibit BEC-CLV-1, Page 4, Column F. These costs (or credits) relate to residual obligations resulting from Boston Edison's former ownership of generation, including Pilgrim, payments in lieu of property taxes, the wholesale revenue credit and Securitization Payments relating to the termination of the purchased power contract with MASSPOWER. The amount of each cost or credit is shown in summary form on page 1.

Q. Please describe the Payments in Lieu of Property Taxes shown in Exhibit BEC-CLV-2, Page 2.

A. In conjunction with the sale of Pilgrim, Boston Edison negotiated a settlement agreement with the Town of Plymouth ("Plymouth") concerning the potential loss of property taxes resulting from the sale. The settlement agreement, which was approved by the Department in Boston Edison Company, D.T.E. 98-53 (1999), requires Boston Edison to make specified payments in addition to or in lieu of property taxes annually through 2012. The amount shown in Column A for 2005 is the actual payments to Plymouth; future years reflect the required payments to Plymouth under the terms of the settlement agreement. Column B is the partial reimbursement (if any) to Boston Edison by Entergy (Pilgrim's current owner) of such payments to Plymouth. Such reimbursement by Entergy was offset to the extent that Entergy was separately taxed by Plymouth. Under the agreement with Entergy, there will be no Entergy reimbursement payments beyond fiscal year 2002; however, if such payments are made, Boston Edison will include them in its final reconciliation for the year in which they occur. Column C is Boston Edison's net payment to Plymouth. Column D shows the Contract Customer Share (22 percent) that will be paid by Boston Edison's two former wholesale contract customers of Pilgrim's output. Column E is the sum of Boston Edison's payment to Plymouth and the Contract Customer Share.

Q. Please explain the Claims and Recoveries shown on Page 3 of Exhibit BEC-CLV-2.

A. Claims and Recoveries consist of two components: (i) Nuclear Electric Insurance Limited ("NEIL") insurance refunds; (ii) Maxey Flats expenses. The NEIL refund reflects amounts that Entergy has received from NEIL. Under the terms of the Pilgrim Purchase and Sale agreement, Boston Edison is entitled to 85 percent of such refunds. Boston Edison, in turn, refunds 22 percent of its share of refunds to its former contract customers and returns the remaining amounts to its retail customers through this adjustment. These funds have not yet been received, but are required to be paid by Entergy by December 31, 2005. In the event the actual amount received is different, it will be reconciled in the final true up.

Payments for Maxey Flats are actual amounts paid (or received) in 2005. Again, this payment is net of a 22 percent recovery of the total expenses from Boston Edison's former contract customers.

Q. Please describe Page 4, Wholesale Revenue Credit.

A. The Department's order in D.T.E. 99-107-A (Phase II) required Boston Edison to change the way it determined and recovered costs associated with its wholesale power business. The Department directed Boston Edison to reconcile wholesale costs and revenues in the Transition Charge, rather than through the Standard Offer and Default Service reconciliation. To comply with that directive, Boston Edison removed all wholesale costs and fuel revenues from the Standard Offer and Default Service reconciliation. The wholesale supply cost, through the end of Standard Offer Service on February 28, 2005, is determined by applying a wholesale/retail ratio to the total cost of power for Standard Offer Service customers. The calculation of this amount is shown on Page 6 of Exhibit BEC-CLV-4. Wholesale supply costs, after March 1, 2005, are the direct costs paid by the Company to provide power to wholesale customers. The remaining wholesale power contract ended on October 31, 2005. The Department also required Boston Edison to include a revenue credit of $35.4 million annually in retail distribution rates to reflect demand charges collected from wholesale customers. The Department directed Boston Edison to account for costs and revenues by: (i) removing all costs and fuel revenues associated with wholesale sales from the

Standard Offer and Default Service reconciliation; (ii) including those costs in the Transition Charge reconciliation; and (iii) requiring that all wholesale revenues, including those associated with demand payments, be reconciled with wholesale costs. In this way, all mitigation revenues collected from wholesale contracts are credited to retail customers, either through the $35.4 million per year distribution rate credit or through the Transition Charge.

In this filing, the 2005 estimated wholesale revenues and supply costs are established using eight months actual and four months estimated values. The 2006 and beyond wholesale revenue and supply costs are estimates based on Boston Edison's current forecast.

Q. Please describe Page 5, Securitization True-up.

A. This true-up adjustment as settled and approved in D.T.E. 01-78 (Phase II), reconciles the amount received by the Securitization fund from the Transition payments as reflected in the Routine True-Up Letters with the amount contributed from the transition payments to the securitization fund as reflected in the transition charge true-up. This true-up shows the actual receipts into the securitization fund from the transition charge (RTC Component). It does so by taking the difference between the beginning balance and the ending balance of the fund for each year (Cols. A and F), adds back payments from the fund bondholders for principal and interest (Cols. B and C), adds back fund expenses (Col. E) and subtracts interest earned by the fund (Col. D). This then shows the actual amount received by the Securitization fund from the transition charge (Col. G). This amount is grossed up (Col. H) by the charge-off rate percentage on page 2, line (s) of the Routine True-up letter, "Annual RTC charge-offs for most recent reconciliation period (per annum)", and used in the calculation on line (q) of the Routine True-up letter. The difference between the amount of transition revenues related to the Securitization filing (Col. I) and the amount shown as collectible in the Transition Charge (Col. J) is an adjustment to the transition charge and is shown in Column K

Q. Please describe Page 6, DOE/SNF Litigation Costs.

A. As approved by the Department on September 9, 2004 in the D.T.E. 03-117-A (Phase II) Settlement Agreement, this page shows the litigation expenses incurred by the Company during 2005 in its pursuit of damages against the U.S. Department of Energy ("DOE"), for breach of contract, caused by DOE's failure to meet its obligations under the Nuclear Waste Policy Act of 1982 ("NWPA"), and its contract with the Company to begin removal and disposal of Spent Nuclear Fuel and high-level nuclear waste ("SNF") at Pilgrim. Pursuant to NWPA, DOE entered into a "Standard Contract" with each of the nation's commercial nuclear power plant owners (including Pilgrim), which required DOE, in return for payments of substantial fees by the commercial nuclear power plant owners into a Nuclear Waste Fund created by NWPA, to commence accepting and permanently disposing of the SNF from the nuclear facilities by

January 31, 1998. The Company sold Pilgrim to Entergy on July 13, 1999. As part of the sales transaction for Pilgrim, the Company assigned its DOE Standard Contract (which was then in breach) to Entergy, subject to a reservation of certain rights and claims which are the subject of the DOE litigation. The Purchase and Sale Agreement entered into by the Company and Entergy on November 18, 1998, expressly reserved to the Company all claims against DOE relating to the Standard Contract up to the closing date of the sale. As a direct and proximate result of the DOE's failure to meet its statutory and contractual obligations to remove SNF up to the date of sale, it is believed the Company suffered significant monetary damages in two categories: (a) diminution of the market value of Pilgrim, which caused the Company to realize less value in the sale than it would have received had DOE met its obligations under NWPA and the Standard Contract; and (b) increased costs incurred by the Company to store and maintain SNF. Per the Department-approved Settlement Agreement in D.T.E. 03-117-A (Phase II), the Company is allowed recovery of these and future litigation costs in its attempt to recover damages from the DOE's breach of contract. In the event the Company is awarded future damages, its customers would receive the benefit.

Q. What is the purpose of the Boston Edison's Securitization Payment Schedule in Exhibit BEC-CLV-2, Page 7?

A. The purpose is to show the recovery of transition costs relating to Boston Edison's termination of a power purchase agreement ("PPA") with

MASSPOWER through the issuance of electric rate reduction bonds (the "RRB Transaction"). The schedule shows the amount of projected Reimbursable Transition Cost ("RTC") revenues (Col. B), the scheduled semi-annual rate reduction bond ("RRB") principal (Col. C) and interest (Col. D) payments, ongoing transaction costs (Col. E), the required annual overcollateralization amount (Col. F), interest earned on trust fund accounts (Col. G) and a gross-up for securitization charge-offs (Col. I). The sum of the projected RTC revenues (Col. B) and the gross-up for securitization charge-offs (Col. I) totals the Estimated Variable Component Collections (Col. J), which flows to Exhibit BEC-CLV-2, Page 1, Column G and represents the amount collectable from customers through the Transition Charge.

Q. What is the regulatory and statutory basis for the RRB Transaction?

A. In the Restructuring Settlement Agreement (the "Agreement") for Boston Edison, the Department approved a transition charge intended to recover on a fully reconciling basis, all of their transition costs, including the reimbursable transition costs amounts being securitized. Also, while not requiring securitization, G.L. c. 164, §§ 1G and 1H (adopted as part of Chapter 164 of the Acts of 1997 (the "Restructuring Act")) establishes the statutory basis for issuing RRBs that will result in net savings for customers. G.L. c. 164, § 1H(b)(1) provides that the Department may issue a financing order to facilitate the securitization of transition costs. G.L. c. 164, § 1H(b)(2) allows electric companies to apply for such financing orders from the Department by January 1, 1999, or from time to time thereafter.

Q. Please describe the transition costs securitized by the Companies on March 1, 2005 under G.L. c. 164, § 1H.

A. By means of the RRB Transaction, and in accordance with G.L. c. 164, § 1H, Boston Edison received approval on January 21, 2005 in D.T.E. 04-70 to securitize as reimbursable transition costs amounts: (1) payments associated with the termination of Boston Edison's obligations pursuant to PPAs with MASSPOWER; (2) the upfront transaction costs of issuing the RRBs; (3) the ongoing transaction costs of the RRBs; and (4) any required credit enhancement in connection with the RRBs. The reimbursable transition costs amounts securitized were based on the closing of the RRB Transaction on March 1, 2005. Components of the reimbursable transition costs amounts are described in more detail below.

1. <u>Contract Buyout Costs.</u>

In connection with the termination of the obligations under the MASSPOWER contracts, Boston Edison received approval of the contract liquidation payments, which released Boston Edison and their customers from their obligations under the remaining term of the PPAs, in an order from the Department (D.T.E. 04-61). Pursuant to the order, the Company received Department approval of such amounts as reimbursable transition costs amounts and to include the right to recover such amounts through the applicable transition charge (the "RTC Charge").

2. Upfront Transaction Costs of Issuing RRBs.

Boston Edison incurred upfront transaction costs related to issuance of RRBs, in order to issue RRBs and achieve net savings for the benefit of its customers. G.L. c. 164, § 1H specifically provides that a financing order shall include recovery of the costs of issuing RRBs and defines Transition Property to include the costs of providing, issuing, servicing and retiring RRBs. In conformity with Boston Edison's prior securitization, the Company received approval to recover the transaction costs of issuing RRBs as reimbursable transition costs amounts out of the proceeds of the RRB Transaction and to include the right to recover such amounts as Transition Property. The recovery of such Transition Property is reflected in the RTC Charge.

3. Ongoing Transaction Costs.

Boston Edison received approval for recovery of ongoing transaction costs as reimbursable transition costs amounts through the RTC Charge in accordance with G.L. c. 164, § 1H, and the right to recover these reimbursable transition costs amounts constitute Transition Property.

Q. What is Boston Edison's principal balance of RRBs approved to be issued?

A. Boston Edison received approval and issued a principal amount of the RRBs of $265.5 million on March 1, 2005.

Q. How will Boston Edison ensure that customers pay the appropriate amounts?

A. Boston Edison has established a memorandum account. Through this non-cash account the Company will account for, and ultimately credit to customers, any amounts remaining in the collection account and the various subaccounts of Boston Edison's Special Purpose Entity ("SPE") other than amounts in the capital subaccount, after such SPE's Total Payment Requirements have been discharged. These amounts will be released to the SPE in accordance with G.L .c. 164, § 1H(b)(7) upon discharge of such SPE's Total Payment Requirements. These benefits will inure to the benefit of customers through a credit to their transition charge.

Q. Was Department approval required as a condition of the MASSPOWER Agreement?

A. Yes. Boston Edison had to receive a final order from the Department approving the buyout of the MASSPOWER PPAs in accordance with the MASSPOWER Agreement and approving the full recovery of payments made pursuant under the MASSPOWER Agreement through the RTC Charge.

Q. Please describe Page 8, Residual Standard Offer Revenues.

A. Standard Offer Service ended on February 28, 2005. The Standard Offer Deferral calculation also ended on that date. However, cycle billing conventions allow for the billing of Standard Offer Revenues in March 2005. Also, cancellation and rebilling of bills rendered to Standard Offer customers has occurred from March 2005 to the present. Page 8 accumulates these two sources of revenues by month and by class and returns it to customers through the transition charge.

Exhibit BEC-CLV-3

Q. Please describe Exhibit BEC-CLV-3.

A. Exhibit BEC-CLV-3 shows how FERC-approved transmission costs are charged to the Company's retail customers. The first page of this exhibit derives the proposed average retail transmission rate to be effective January 1, 2006, based on the current forecast for 2006 retail transmission costs in FERC-approved tariffs. The second page includes a preliminary true up for 2005 retail transmission costs. The proposed Transmission Charge for the Company, beginning on January 1, 2006, is $0.01312 per kWh.

Q. What changes are you proposing for the Transmission Cost Reconciliation exhibit?

A. There are two changes in the Transmission Cost Reconciliation exhibit from the Company's filing in last year's proceedings in D.T.E. 04-113. The first change reorganizes the format to group costs with other similar items. The second change is to include a new regional cost component line item starting in January 2005. This cost item reflects the Company's share of the cost responsibility associated with receiving load dispatching services provided by the REMVEC satellite system. The cost is billed to the Company by National Grid, the operator of REMVEC. The REMVEC expenses were not being recovered prior to 2004 because they were not included the Company's OATT Revenue Requirement as shown on Page 2, Line 12 of the reconciliation exhibit.

Q. Generally, what are the transmission costs that are included in the total retail transmission costs?

A. The retail transmission costs are those costs associated with providing Regional and Local Network transmission service to the retail class that utilize an integrated grid of transmission facilities that comprise both POOL Transmission Facilities ("PTF") and Non-PTF. The operation and control of the PTF is governed by ISO New England, Inc. (the "ISO") and the costs of the facilities are administrated as such by the ISO under the applicable provisions and schedules of the FERC-approved ISO New England Open Access Transmission Tariff. The Non-PTF costs are administered by the Company in accordance with the applicable Local Service Schedules within the ISO New England Open Access Transmission Tariff.

Q. What are the individual component costs that are assessed to the retail class under the ISO New England Open Access Transmission Tariff?

A. Under the ISO New England Open Access Transmission Tariff, transmission costs are assessed for Regional Network Service, Scheduling and Dispatch service at the regional level, Congestion Management, system restoration and planning costs, and administration costs. Congestion Management costs consist of both Special Constrained Resources ("SCR") and Reliability Must Run ("RMR") costs. Under the Local Service Schedules, the transmission costs that are assessed are Local Network Service and Scheduling and Dispatch service at the local level.

V. CALCULATION OF THE STANDARD OFFER SERVICE RECONCILIATION AND DEFAULT SERVICE ADJUSTMENT RATE

Q. Please explain Exhibit BEC-CLV-4.

A. Exhibit BEC-CLV-4 is the reconciliation of Standard Offer Service showing both supply costs and revenues for January and February 2005. The exhibit contains only these two months of actual data because Standard Offer Service ended on February 28, 2005. On page 1, a summary of the Standard Offer Service revenues and costs is shown for each month of 2005. Also shown is the total deferral balance, which adds or subtracts the monthly over- or under-recovery to the prior month balance, adjusts for a carrying charge and calculates the new end-of-month deferral. Page 2 shows the GWh associated with long-term PPAs and the resulting PPA transfer costs. The PPA transfer price (or "DistCo. Settlement Price ($/kWh)") is set at a level that is projected to result in a zero deferral balance, i.e., there will be neither an over-recovery nor an under-recovery of costs in comparison to the projected revenues for Standard Offer Service at the end of each month. Page 3 summarizes the contracted cost of power under the PPAs; the total PPA supply cost is reflected in BEC-CLV-1. Page 4 details the costs for short-term power transactions used to supplement existing resources needed to provide Standard Offer Service. Page 5 shows the revenues and associated GWh sales for Standard Offer Service. Page 6 shows the GWh sales to wholesale customers, and calculates the wholesale percentage of total sales, when total sales are the sum of wholesale and retail standard offer sales.

Q. Please explain Exhibit BEC-CLV-5.

A. The first page of Exhibit BEC-CLV-5 is the reconciliation of Basic Service showing both preliminary supply costs and revenues for the year 2005. The exhibit contains eight months of actual data and four months of projected data. Basic Service revenues and costs are shown for each month of 2005. Also shown is the total deferral balance, which adds or subtracts the monthly over- or under-recovery to the prior month balance, adjusts for a carrying charge and calculates the new end-of-month deferral. Page two of this exhibit reflects the forecast for the reconciliation of Basic Service showing both supply costs and revenues for the year 2006.

Q. Please explain the Default Service Adjustment and the rate the Company is proposing.

A. The Default Service Adjustment recovers the prior year's Default Service Deferral Balance. The Company's proposed Default Service Adjustment rate for the year 2006 is set at $0.00065 per kWh. In 2005, the Company did not have a Default Service Adjustment rate. In accordance with Department requirements and the Company's tariffs, this rate will be applied to all customers.

Q. What is the source for Standard Offer and Basic Service revenues shown in Exhibits BEC-CLV-4 and BEC-CLV-5?

A. The revenues through August 2005 for Standard Offer Service and Default Service are taken from the Company's general ledger; forecast revenues are reflected for the September through December 2005 period and for calendar year 2006. The Basic Service rates for 2006 reflect the rates filed by the Company that were approved by the Department.

Q. How did the Company calculate expenses for Standard Offer Service as shown in this filing for 2005?

A. There are two expense categories incurred to provide Standard Offer Service: power-purchase contracts and short-term market transaction. The power-purchase contracts are purchased under long-term commitments made before industry restructuring. The costs of these contracts are included as a variable transition cost and are "purchased" to provide Standard Offer Service at a transfer price. As stated above the PPA transfer prices (or "DistCo Settlement Price ($/kWh)") are set at a level that is projected to result in a zero deferral balance at the end of each month, i.e., there will be neither an over-recovery nor an under-recovery of costs in comparison to the projected revenues for Standard Offer Service. The costs of short-term market transactions are added to the costs of the power-purchase contracts and reduced by the amount attributed to wholesale sales in accordance with the Department's decision in D.T.E. 99-107 (Phase II).

Q. How did the Company calculate expenses for Basic Service in this filing?

A. In 2005, the Company purchased supplies for Basic Service from the competitive market through dedicated contracts after issuances of requests for proposals. The costs included through August 2005 are based on actual expenses incurred and for subsequent months are based on projections of costs to be incurred under those contracts.

Q. How are the Standard Offer and Basic Service deferral balances calculated?

A. The monthly deferrals are the difference between revenues and expenses. The deferrals also incorporate an interest component.

Q. Please explain the interest calculation.

A. The Standard Offer Service and Basic Service deferrals accrue interest at the rate for customer deposits in accordance with the Company's approved Restructuring Settlement. The monthly deferral is the difference between the revenues and the cost of supply for each month. For each month, interest is applied to the prior month's cumulative deferral plus one-half the current month's deferral. The monthly interest is then incorporated in the cumulative deferral. The monthly Standard Offer Service interest calculation can be found on page 1 of Exhibit BEC-CLV-4; the monthly Default Service interest calculation can be found on pages 1 and 2 of Exhibit BEC-CLV-5.

Q. Is the Company mitigating its transition costs?

A. Yes. The Act and the approved Restructuring Settlement require that the Company take all reasonable steps to mitigate its transition costs "to the maximum extent possible" and encourages electric companies to divest their generating assets and renegotiate or buy-out of above-market PPAs.

Boston Edison has attempted to divest or renegotiate their respective PPAs since the enactment of the Restructuring Act. Boston Edison discussed its mitigation efforts in three mitigation reports filed with the Department (see Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company, D.T.E. 00-70 (Mitigation Report of NSTAR Electric (January 19, 2001)); Department Investigation of Power Purchase Agreement Mitigation, D.T.E. 99-62 (August 24, 1999 Mitigation Report of Boston Edison Company); Department Investigation of Power Purchase Agreement Mitigation, D.T.E. 98-62 (July 30, 1998 Mitigation Report of Boston Edison Company)). In addition, Boston Edison submitted a PPA Divestiture Plan to the Department in June 1998, which provided for a combination of continued bilateral negotiations with the

PPA sellers and an auction process to assign the rights to the PPA entitlements to be conducted in 1999.

Q. Has the Company been successful in renegotiating or buying out any of its PPA contracts in the past year?

A. Yes. Cost-effective proposals were received for some of the PPAs through an open and competitive bidding process that was administered by Concentric Energy Advisors ("CEA"). As a result, the Company has successfully bought out, bought down or otherwise renegotiated contractual obligations with individual suppliers in a way that has provided mitigation of transition costs for customers as described in D.T.E. 04-61 (MASSPOWER), D.T.E. 04-68 (Ocean State Power) and D.T.E. 04-85 (NEA). The mitigation of these contracts have been approved by the Department.

Q. Why does the Company believe that it has mitigated its transition costs associated with PPAs to the maximum extent possible?

A. Consistent with the Act and the Company's Restructuring Settlement, Boston Edison has successfully mitigated its transition costs associated with PPAs through good-faith renegotiations, restructurings and buy-outs. Customers have realized approximately $91.1 million in savings because of these efforts in 2004 and 2005 and will continue to realize savings in the future if and when the Company further reduces its PPA obligations through renegotiation, sale and buy-outs of these contracts. However, the Company will proceed with a divestiture of a PPA contract only to the extent that the transaction will result in net benefits for its customers. If a divestiture transaction would result in additional costs for customers and not produce maximum mitigation of transition costs, the Company will not pursue it.

Q. Describe how the Company currently obtains Basic Service for its customers.

A. The Company is responsible for supplying retail customers with Basic Service for the year 2006. The Company, jointly with Cambridge and Commonwealth as NSTAR Electric, periodically issue RFPs for Basic Service.

Basic Service solicitations are performed in accordance with the Department's directives. The Basic Service contract is awarded to the winning bidder with the lowest price in each load zone and customer class. For 2006, NSTAR Electric has recently entered into a three-month contract for large industrial customers and a twelve-month contract for 50 percent of the residential and commercial customers to match an existing 50 percent contract.

Q. Does this conclude your testimony?

A. Yes, it does.

Boston Edison Company
Transition Charge Calculation
$ in Millions

Year	GWH Delivered	Transition Charge	**Revenues for Delivered GWH**	Fixed Component	Total Variable Component	Mitigation Incentive	Prior Year Deferral	Interest on Deferral	**Expenses**	(Over) Under Collection
Col. A	Col. B	Col. C	**Col. D**	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K
2004										$ 22.953
2005	15,714.626	2.012	**316.224**	$ 91.872	$ 175.039	$ 5.649	$ 22.953	$ 2.497	$ 298.010	$ (18.214)
2006	15,810.868	1.916	**302.902**	**87.222**	**230.667**	**5.208**	**(18.214)**	**(1.982)**	**302.902**	**-**
2007	16,127.085	1.956	**315.435**	82.339	229.500	3.596	-	-	**315.435**	-
2008	16,449.627	1.783	**293.261**	77.756	212.301	3.204	-	-	**293.261**	-
2009	16,778.620	1.703	**285.751**	72.833	210.588	2.330	-	-	**285.751**	-
2010	17,114.192	1.295	**221.553**	15.174	206.379	-	-	-	**221.553**	-
2011	17,456.476	0.737	**128.663**	-	128.663	-	-	-	**128.663**	-
2012	17,805.606	0.461	**82.146**	-	82.146	-	-	-	**82.146**	-
2013	18,161.718	0.258	**46.830**	-	46.830	-	-	-	**46.830**	-
2014	18,524.952	0.222	**41.213**	-	41.213	-	-	-	**41.213**	-
2015	18,895.451	0.216	**40.807**	-	40.807	-	-	-	**40.807**	-
2016	19,273.360	0.178	**34.240**	-	34.240	-	-	-	**34.240**	-

Col. B: 2005 per Page 2, Line 15; 2006 per sales forecast; years 2007 and beyond assumes 2% growth per anum.
Col. C: 2005 per Page 2, Line 15; 2006 and beyond equals Col. J / Col. B.
Col. D: 2005 per Page 2, Line 15; 2006 and beyond equals Col. J.
Col. E: Page 3, Col. E.
Col. F: Page 4, Col. I.
Col. G: Page 5, Col. E.
Col. H: Col. K prior year.
Col. I: Col. H times 10.88%
Col. J: Sum of Col. E thru Col. I.
Col. K: 2004 per D.T.E. 04-113 (Supp); 2005 and beyond equals Col. J - Col D.

Boston Edison Company
Estimated 2005 Transition Revenues
$ in Millions

Line	Description	GWH	A/C #	Per Book $	Total
1	Estimated 2005 Transition Billed Revenues:				
2	Residential Transition	4,427.476	440 160	$ 88.664	
3	Industrial Transition	1,269.492	442 430	25.181	
4	Commercial Transition (includes WR rate and Special Contracts)	9,772.532	442440/500	190.465	
5	Street Light Transition	143.152	444 060	2.945	
6	Total Billed Revenues	15,612.652			**$ 307.255**
7	Estimated 2005 Transition Unbilled Revenues:			Value	
8	Less: Residential Transition Unbilled @ 12/31/04	(201.353)			
9	Plus: Residential Transition Unbilled @ 12/31/05	208.093	440 162	$ (0.011)	
10	Less: Industrial Transition Unbilled @ 12/31/04	(50.241)			
11	Plus: Industrial Transition Unbilled @ 12/31/05	67.075	442 435	1.137	
12	Less: Commercial Transition Unbilled @ 12/31/04	(398.932)			
13	Plus: Commercial Transition Unbilled @ 12/31/05	477.332	442 505	7.843	
14	Total Unbilled Revenues	101.974			**$ 8.969**
15	Total Estimated 2005 Transition Revenues	15,714.626	2.012		**$ 316.224**

Boston Edison Company
Summary of Transition Charge - Fixed Component
$ in Millions

Year	Securitization Principal	Amort.	Interest & Expense	Total
Col. A	Col. B	Col. C	Col. D	Col. E
				(Col. C + Col. D)
2005	$ 288.206	$ 68.460	$ 23.412	$ 91.872
2006	219.664	68.542	18.680	87.222
2007	151.268	68.396	13.943	82.339
2008	82.660	68.608	9.148	77.756
2009	14.159	68.501	4.332	72.833
2010	-	14.159	1.016	15.174

Boston Edison Company
Summary of Transition Charge - Variable Component
$ in Millions

Year	Actual Power Total Obligations	Actual Power Contracts Market Value	Net Power Obligation	Actual Purchased Power Contract Buyouts	Revenue Credits & Damages, Costs, or net Recoveries	Rate Design Adjustment	Reversal of Prior Year Rate Design Adjustment	Actual Total Variable Component
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I
2005	$ 210.949	$ 93.611	$ 117.338	$ -	$ 64.502	$ (11.488)	$ 4.687	$ 175.039
2006	216.182	72.791	143.391	-	88.854	(13.066)	11.488	230.667
2007	205.795	70.670	135.125	-	81.309	-	13.066	229.500
2008	207.459	71.855	135.604	-	76.697	-	-	212.301
2009	209.434	74.179	135.255	-	75.333	-	-	210.588
2010	210.076	77.675	132.401	-	73.978	-	-	206.379
2011	127.597	71.532	56.065	-	72.598	-	-	128.663
2012	64.262	52.865	11.397	-	70.749	-	-	82.146
2013	61.093	55.336	5.757	-	41.073	-	-	46.830
2014	63.082	57.269	5.813	-	35.400	-	-	41.213
2015	64.205	58.798	5.407	-	35.400	-	-	40.807
2016	43.151	44.311	(1.160)	-	35.400	-	-	34.240

Note	Description
Col. B:	Page 6, Col. P.
Col. C:	Page 7, Col. Q.
Col. D:	Col. B - Col. C (see also Page 8, Col. Q).
Col. F:	per Exhibit BEC-CLV-2, Page 1, Col. L.
Col. G:	Exhibit BEC-HCL-7, Page 1, Col. E.
Col. H:	Reversal of Prior Year Col. G.
Col. I:	Col. D + Col. E + Col. F + Col. G + Col. H.

Boston Edison Company
Summary of Transition Charge - Incentive
$ in Millions

Year	Base Transition Charge (cents/kWh)	Cumulative Rolling Average Transition Charge (cents/kWh)	Cumulative Bonus Allowed	Nominal Annual Incremental Bonus Required	Impact on Transition Charge
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F
2004	1.808	2.00	63.913	8.962	0.06
2005	2.012	2.01	67.297	5.649	0.04
2006	1.916	2.00	70.225	5.208	0.03
2007	1.956	1.99	72.121	3.596	0.02
2008	1.783	1.97	73.705	3.204	0.02
2009	1.703	1.95	74.786	2.330	0.01

Legend:

Col. B	Exh. BEC-CLV-1 , Page 1, Col. C.
Col. C	Cumulative average of current & prior years shown in Col. B.
Col. D	For any given year based upon cumulative average transition charge, interpolate bonus from the table below:
Col. E	(Col. D current year - Col. D prior year) * (1 + WACC AT) ^ n, where n = number of years since 1998 +1, and WACC AT is the weighted cost of capital after-tax equal to 6.61%
Col. F	Col. E / Current year GWH sales, Page 1, Col. B.

Note: per D.P.U./D.T.E. 96-23, Settlement Page 244.

Assumptions:
1998 $ NPV Cumulative Bonus/(Penalty)

Rolling Average Access Charge

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
1.00	$ 21	$ 38	$ 52	$ 63	$ 72	$ 80	$ 85	$ 90	$ 93	$ 96	$ 97	$ 98
1.20	20	36	49	60	68	76	81	86	89	91	92	93
1.40	19	34	47	57	65	72	77	81	84	86	88	88
1.60	18	32	44	53	61	68	73	77	79	81	83	83
1.80	17	31	41	50	58	64	68	72	75	77	78	78
2.00	16	29	39	47	54	60	64	68	70	72	73	74
2.20	14	25	34	41	47	52	56	59	61	62	63	64
2.40	12	21	29	35	40	44	47	50	51	53	54	54
2.60	10	17	23	28	33	36	39	41	42	43	44	44
2.80	8	13	18	22	25	28	30	32	33	34	34	34
3.00	5	10	13	16	18	20	22	23	24	24	25	25
3.20	3	6	8	10	11	12	13	14	14	15	15	15
3.40	1	2	3	3	4	4	4	5	5	5	5	5
3.50	0	0	0	0	0	0	0	0	0	0	0	0

Boston Edison Company
Power Contract Obligations
Annual Total Cost - Capacity & Energy ($ in Millions)

Year	OSP	NEA A	NEA B	Masspower	MBTA Jets 1	MBTA Jets 2	HQ 1	HQ 2	HQ Line Usage	Misc. Trans.	ISO-NE	Renew. Cert.	Conn Yankee	MA Yankee	Total
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O	Col. P
Jan - Feb	$ 3.627	$ (13.591)	$ 18.881	$ 11.143	$ (0.101)	$ 0.468	$ 0.245	$ 0.857	$ (0.180)	$ -	$ -	$ -	$ 1.291	$ 0.865	$ 23.505
Mar - Dec	17.932	75.741	78.697	(4.618)	1.015	2.130	0.930	3.718	(1.136)	0.103	(0.810)	(0.363)	9.791	4.315	187.444
2005	$ 21.559	$ 62.150	$ 97.579	$ 6.524	$ 0.913	$ 2.598	$ 1.174	$ 4.575	$ (1.316)	$ 0.103	$ (0.810)	$ (0.363)	$ 11.082	$ 5.181	$ 210.949
2006	22.600	75.139	89.273	-	-	2.556	1.187	5.186	(2.000)	0.160	-	-	15.842	6.240	216.182
2007	21.760	74.036	91.220	-	-	2.595	1.163	5.082	(2.000)	0.160	-	-	10.541	1.238	205.795
2008	21.060	76.045	93.415	-	-	2.600	1.140	4.981	(2.000)	0.160	-	-	8.835	1.223	207.459
2009	18.920	77.738	95.020	-	-	2.606	1.303	5.629	(2.000)	0.160	-	-	8.835	1.223	209.434
2010	13.880	80.719	98.095	-	-	2.612	1.232	5.320	(2.000)	0.160	-	-	8.835	1.223	210.076
2011	5.200	62.427	53.019	-	-	2.619	1.160	5.012	(2.000)	0.160	-	-	-	-	127.597
2012	-	57.687	-	-	-	2.623	1.089	4.703	(2.000)	0.160	-	-	-	-	64.262
2013	-	54.891	-	-	-	2.629	1.017	4.396	(2.000)	0.160	-	-	-	-	61.093
2014	-	57.253	-	-	-	2.636	0.946	4.087	(2.000)	0.160	-	-	-	-	63.082
2015	-	58.752	-	-	-	2.640	0.875	3.778	(2.000)	0.160	-	-	-	-	64.205
2016	-	38.076	-	-	-	2.642	0.803	3.470	(2.000)	0.160	-	-	-	-	43.151

Note: 2005 (Jan - Feb) per Exhibit BEC-CLV-4, Page 3.
2005 (Mar - Dec) - 6 months actual, 4 months forecast.
Post 2005 per Company forecasts.

Boston Edison Company
Power Contract Obligations
Annual Market Value ($ in Millions)

Year	OSP	NEA A	NEA B	Masspower	MBTA Jets 1	MBTA Jets 2	HQ 1	HQ 2	HQ Line Usage	Misc. Trans.	ISO-NE	Renew. Cert.	Conn Yankee	MA Yankee	Other Adjusment	Total
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O	Col. P	Col. Q
Jan - Feb	$ -	$ 2.543	$ 1.583	$ 2.555	$ (0.001)	$ (0.001)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6.678
Mar - Dec	-	53.169	31.312	2.351	0.041	0.060	-	-	-	-	-	-	-	-	-	86.932
2005	$ -	$ 55.713	$ 32.894	$ 4.905	$ 0.040	$ 0.059	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 93.611
2006	-	45.039	27.693	-	-	0.059	-	-	-	-	-	-	-	-	-	72.791
2007	-	42.123	25.932	-	-	0.056	-	-	-	-	-	-	-	-	2.559	70.670
2008	-	43.463	26.757	-	-	0.059	-	-	-	-	-	-	-	-	1.576	71.855
2009	-	44.762	27.556	-	-	0.061	-	-	-	-	-	-	-	-	1.800	74.179
2010	-	46.876	28.858	-	-	0.065	-	-	-	-	-	-	-	-	1.876	77.675
2011	-	48.747	20.719	-	-	0.069	-	-	-	-	-	-	-	-	1.997	71.532
2012	-	50.487	-	-	-	0.074	-	-	-	-	-	-	-	-	2.304	52.865
2013	-	52.731	-	-	-	0.081	-	-	-	-	-	-	-	-	2.524	55.336
2014	-	54.733	-	-	-	0.085	-	-	-	-	-	-	-	-	2.451	57.269
2015	-	56.232	-	-	-	0.091	-	-	-	-	-	-	-	-	2.475	58.798
2016	-	41.391	-	-	-	0.095	-	-	-	-	-	-	-	-	2.825	44.311

Note: 2005 (Jan - Feb) per Exhibit BEC-CLV-4, Page 2.
2005 (Mar - Dec) - 6 months actual, 4 months forecast.
Post 2005 per Company forecasts.

Boston Edison Company
Power Contract Obligations
Annual Above Market Cost ($ in Millions)

Year	OSP	NEA A	NEA B	Masspower	MBTA Jets 1	MBTA Jets 2	HQ 1	HQ 2	HQ Line Usage	Misc. Trans.	ISO-NE	Renew. Cert.	Conn Yankee	MA Yankee	Other Adjustment	Total
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O	Col. P	Col. Q
Jan - Feb	$ 3.627	$ (16.134)	$17.299	$ 8.588	$ (0.100)	$0.469	$0.245	$0.857	$ (0.180)	$ -	$ -	$ -	$ 1.291	$ 0.865	$ -	$ 16.826
Mar - Dec	17.932	22.571	47.385	(6.969)	0.974	2.070	0.930	3.718	(1.136)	0.103	(0.810)	(0.363)	9.791	4.315	-	100.512
2005	$21.559	$ 6.437	$64.684	$ 1.619	$ 0.873	$2.539	$1.174	$4.575	$ (1.316)	$0.103	$ (0.810)	$ (0.363)	$11.082	$ 5.181	$ -	$117.338
2006	22.600	30.100	61.580	-	-	2.497	1.187	5.186	(2.000)	0.160	-	-	15.842	6.240	-	143.391
2007	21.760	31.913	65.288	-	-	2.539	1.163	5.082	(2.000)	0.160	-	-	10.541	1.238	(2.559)	135.125
2008	21.060	32.582	66.658	-	-	2.541	1.140	4.981	(2.000)	0.160	-	-	8.835	1.223	(1.576)	135.604
2009	18.920	32.976	67.464	-	-	2.545	1.303	5.629	(2.000)	0.160	-	-	8.835	1.223	(1.800)	135.255
2010	13.880	33.843	69.237	-	-	2.547	1.232	5.320	(2.000)	0.160	-	-	8.835	1.223	(1.876)	132.401
2011	5.200	13.680	32.300	-	-	2.550	1.160	5.012	(2.000)	0.160	-	-	-	-	(1.997)	56.065
2012	-	7.200	-	-	-	2.549	1.089	4.703	(2.000)	0.160	-	-	-	-	(2.304)	11.397
2013	-	2.160	-	-	-	2.548	1.017	4.396	(2.000)	0.160	-	-	-	-	(2.524)	5.757
2014	-	2.520	-	-	-	2.551	0.946	4.087	(2.000)	0.160	-	-	-	-	(2.451)	5.813
2015	-	2.520	-	-	-	2.549	0.875	3.778	(2.000)	0.160	-	-	-	-	(2.475)	5.407
2016	-	(3.315)	-	-	-	2.547	0.803	3.470	(2.000)	0.160	-	-	-	-	(2.825)	(1.160)

Note: Annual Above Market = Annual Obligation (page 6) minus Annual Market (page 7).

Boston Edison Company
Revenue Credits & Damages, Costs, or Net Recoveries from Claims
$ in Millions

Year	Payment in Lieu of Property Tax	Claims and Recoveries	Sales of Property	Wholesale Revenue Credit	BEC I Securitization True-Up	DOE/SNF Litigation	BEC II Securitization Payment	Future Use	Standard Offer Revenues	Securitization Transaction Cost True-up	Other PPA Transaction Costs	Total
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
2005	$ 9.750	$ (1.326)	$ -	$ 37.026	$ 1.000	$ 0.464	$ 36.381	$ -	$ (18.794)	$ -	$ -	$ 64.502
2006	8.970	-	-	35.400	-	-	44.484	-	-	-	-	88.854
2007	4.680	-	-	35.400	-	-	41.229	-	-	-	-	81.309
2008	0.780	-	-	35.400	-	-	40.517	-	-	-	-	76.697
2009	0.780	-	-	35.400	-	-	39.153	-	-	-	-	75.333
2010	0.780	-	-	35.400	-	-	37.798	-	-	-	-	73.978
2011	0.780	-	-	35.400	-	-	36.418	-	-	-	-	72.598
2012	0.390	-	-	35.400	-	-	34.959	-	-	-	-	70.749
2013	-	-	-	35.400	-	-	5.673	-	-	-	-	41.073
2014	-	-	-	35.400	-	-	-	-	-	-	-	35.400
2015	-	-	-	35.400	-	-	-	-	-	-	-	35.400
2016	-	-	-	35.400	-	-	-	-	-	-	-	35.400

Notes: Col. A per Page 2.
Col. B per Page 3.
Col. D per Page 4.
Col. E per Page 5.
Col. F per Page 6.
Col. G per Page 7.
Col. I per Page 8.
Col. L equals Sum of Col. A thru Col. K.

Boston Edison Company
Payments in Lieu of Property Taxes
$ in Millions

Year	Actual/Required Payment to Town	Entergy Direct Payments	Net BECo Payments	Contract Customer Share	Net
	Col. A	Col. B	Col. C	Col. D	Col. E
2005	$ 12.500	$ -	$ 12.500	$ (2.750)	$ 9.750
2006	11.500	-	11.500	(2.530)	8.970
2007	6.000	-	6.000	(1.320)	4.680
2008	1.000	-	1.000	(0.220)	0.780
2009	1.000	-	1.000	(0.220)	0.780
2010	1.000	-	1.000	(0.220)	0.780
2011	1.000	-	1.000	(0.220)	0.780
2012	0.500	-	0.500	(0.110)	0.390

Notes: Col. A Actual property tax payment for 2005, future years per tax agreement with Town of Plymouth Approved in D.T.E. 98-53.
Col. B equals Actual Payments received from Entergy, if any.
Col. C equals Col. A - Col. B.
Col. D equals 22% of Col. C.
Col. E equals Col. C + Col. D.

Boston Edison Company
Claims and Recoveries
$ in Millions

Line			2005
	NEIL Insurance Credit Refund:		
1	Entergy NEIL Credit for Pilgrim	$ (2.000)	
2	Percentage paid to BECo per Pilgrim P & S	85%	
3	BECo Share of Pilgrim NEIL Credit to be received by 12/31	$ (1.700)	
4	Less 22 % Contract Customer Share	0.374	
5	Net NEIL Refund Applicable to Retail Sales		$ (1.326)
6	**Maxey Flats LLC Expenses:**		
7	2005 Maxey Flats Payment	$ -	
8	Less: Payment received from American Ecology	-	
9	Net Maxey Flats Payments	$ -	
10	Less 22 % Contract Purchaser Share	-	
11	Net Maxey Flats Expense Applicable to Retail Sales		$ -
12	**Total Pilgrim Adjustments**		**$ (1.326)**

Boston Edison Company
Wholesale Revenue Credit
$ in Millions

Line	Description	2005	2006	2007	2008
1	Total Wholesale Revenue	$ 9.283	$ -	$ -	$ -
2	Less: Wholesale Supply Cost	10.909	-	-	-
3	Demand Credit in Retail Distribution Rates	35.400	35.400	35.400	35.400
4	Net Wholesale Revenue Transition Cost	$ 37.026	$ 35.400	$ 35.400	$ 35.400

Notes: Line 1-2005 per book revenues (8 months actual, 4 months forecast).
Line 2-January and February 2005 per Exhibit BEC-CLV-4, Page 1, Line 11.
March through December 2005 per book expenses (6 months actual, 4 months forecast).
Line 3 is $35.4 million annually.
Line 4 equals Sum of Line 2 plus Line 3 less Line 1.

Boston Edison Company
BEC Funding I Securitization True-Up
$ in Millions

Year	Ending Securitization Account Balance	RRB Principal Payments	RRB Interest Payments	Less: Interest Earned	Admin Fees	Less: Beginning Securitization Account Balance	Securitization Collections net of Charge-offs	Gross-Up of Securitization Collections Charge-offs @ 0.58%	100% Recoverable Securitization Collections	Fixed Component Collections	Securitization True-Up
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K
2005	$ 29.296	$ 68.402	$ 25.020	$ (0.107)	$ 0.912	$ (31.190)	$ 92.333	$ 0.539	$ 92.872	$ 91.872	$ 1.000
2006		$ 68.604	$ 20.340							$ 87.222	$ -
2007		$ 68.520	$ 15.603							$ 82.339	$ -
2008		$ 68.490	$ 10.848							$ 77.756	$ -
2009		$ 68.504	$ 6.033							$ 72.833	$ -
2010		$ 34.631	$ 1.217							$ 15.174	$ -

Col. A per December 2004 Bank of New York monthly statement
Col. B 2005 - Total of actual RRB principal payments made on March 15 and September 15. 2006-2010 forecast payment schedule.
Col. C 2005 - Total of actual RRB interest payments made on March 15 and September 15. 2006-2010 forecast payment schedule.
Col. D 2005 actual interest earned
Col. E Annual Ongoing Transaction Costs per Issuance Advice Letter dated July 28, 1999, Attachment 2
Col. F - Prior Year actual ending balance
Col. G Sum of Cols. A through F
Col. H (Col. G / (1 - .0058)) - Col. G
2005 Charge-off rate of 0.58% per Accounting Department.
Col. I Col. G + Col. H.
Col. J Exhibit BEC-CLV-1, Page 3.
Col. K 2005 year-end forecast; 2006-2010 is an estimate.

Boston Edison Company
Department of Energy (DOE)/Spent Nuclear Fuel (SNF)
Litigation Expense
$ in Millions

	Invoice Date	Vendor		Invoice Amount	
1	23-Dec-04	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.039	
2	23-Dec-04	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.002	
3	31-Jan-05	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.052	
4	28-Feb-05	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.056	
5	28-Feb-05	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.007	
6	22-Mar-04	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.042	Forecast
7	22-Mar-04	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.002	Forecast
8	27-Apr-04	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.030	Forecast
9	27-Apr-04	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.001	Forecast
10	28-May-04	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.046	Forecast
11	28-May-04	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.001	Forecast
12	29-Jun-04	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.054	Forecast
13	29-Jun-04	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.001	Forecast
14	21-Jul-04	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.064	Forecast
15	21-Jul-04	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.002	Forecast
16	18-Aug-04	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.056	Forecast
17	30-Sep-04	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.000	Forecast
18	30-Sep-04	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.066	Forecast
19	22-Oct-04	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.041	Forecast
20	22-Oct-04	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.000	Forecast
21	19-Nov-04	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.029	Forecast
22	19-Nov-04	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.003	Forecast
23					
24	Subtotal	Dickstein Shapiro Morin & Oshinsky, LLP	$	0.593	
25					
26	16-Mar-04	Shaw Pittman, LLP	$	0.002	Forecast
27					
28	DOE/SNF Litigation Expenses Incurred in 2005		$	0.595	
29	Less: 22% Pilgrim Contract Customer Share*		$	(0.131)	
30	DOE/SNF Litigation Expenses applicable to Retail		$	0.464	

* $65,000 of the Pilgrim Contract Customer Share is being deferred and is subject to collection as a transition cost in the event Boston Edison does not receive compensation from the Department of Energy.

Boston Edison Company
BEC Funding II Securitization
$ in Millions

Year	Beginning Collection & Reserve Account Balance	Plus: Estimated Securitization Collections	Less: RRB Principal Payments	Less: RRB Interest Payments	Less: Ongoing Costs	Less: Overcollat-eralization	Plus: Estimated Interest Earned	Ending Collection & Reserve Account Balance	Gross-Up of Securitization Collections Charge-offs @ 0.58%	Estimated Variable Component Collections
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J
2005	$ -	$ 36.312	$ (13.009)	$ (5.708)	$ (0.103)	$ (0.083)	$ 0.144	$ 17.553	$ 0.213	$ 36.381
2006	17.553	44.323	(37.212)	(9.806)	(0.191)	(0.166)	0.100	14.602	0.261	44.484
2007	14.602	41.090	(32.229)	(8.551)	(0.191)	(0.166)	0.100	14.654	0.239	41.229
2008	14.654	40.379	(33.408)	(7.315)	(0.191)	(0.166)	0.100	14.054	0.238	40.517
2009	14.054	39.024	(33.144)	(5.985)	(0.191)	(0.166)	0.100	13.691	0.229	39.153
2010	13.691	37.678	(33.211)	(4.615)	(0.191)	(0.166)	0.100	13.286	0.220	37.798
2011	13.286	36.306	(33.191)	(3.244)	(0.191)	(0.166)	0.100	12.900	0.212	36.418
2012	12.900	34.855	(33.201)	(1.832)	(0.191)	(0.166)	0.100	12.465	0.204	34.959
2013	12.465	5.665	(16.894)	(0.372)	(0.095)	(0.083)	0.025	0.711	0.033	5.673
Total		$ 315.633	$ (265.500)	$ (47.428)	$ (1.534)	$ (1.328)	$ 0.869	$ 0.711	$ 1.848	$ 316.612

Col. A Col. H prior year
Col. B RTC collections estimate
Col. C RRB principal payments made on March 15 and September 15.
Col. D RRB interest payments made on March 15 and September 15.
Col. E Attachment 2 of Issuance Advice Letter dated 2/18/05
Col. F Attachment 2 of Issuance Advice Letter dated 2/18/06
Col. G Estimated interest earned
Col. H Sum of Cols. A to G
Col. I (Col. B / (1 - .0058)) - Col. B
Col. J Col. B - Col. G + Col. I

Boston Edison Company
Post Standard Offer Period Revenues
$ in Millions

Line	Description	Account	Actual Mar-05	Actual Apr-05	Actual May-05	Actual Jun-05	Actual Jul-05	Actual Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Total
1	Standard Offer Revenues												
2	Residential	440170	$ 7.825	$ 0.021	$ (0.019)	$ (0.013)	$ (0.010)	$ (0.007)	$ -	$ -	$ -	$ -	$ 7.797
3	Commercial	442450	9.677	0.377	(0.037)	(0.016)	(0.015)	(0.015)	-	-	-	-	9.972
4	Industrial	442460	0.847	0.021	0.003	0.000	0.000	0.000	-	-	-	-	0.872
5	Street Light	444070	0.152	(0.003)	(0.003)	(0.000)	(0.000)	0.007	-	-	-	-	0.153
6	Total Standard Offer Revenues		$ 18.502	$ 0.416	$ (0.056)	$ (0.029)	$ (0.025)	$ (0.014)	$ -	$ -	$ -	$ -	$ 18.794

Boston Edison Company
2006 Retail Transmission Rate Forecast
$ in Millions

Line	Description	Total
	Regional Transmission Costs	
1	Retail RNS Cost	$ 67.575
2	Regional Anciliary Services	
3	Retail Schedule & Dispatch Cost	4.500
4	Retail Congestion Management Cost	109.998
5	System Restoration & Planning Cost	1.100
6	Load Dispatching (REMVEC)	0.270
7	NEPOOL Administration (Transmission)	0.071
8	VAR Support Cost	-
9	Total Estimated Regional Transmission Costs	183.514
10	**Local Transmission Costs**	
11	Determination of Local Network Service (LNS) Costs	
12	OATT and Scheduling & Dispatch Revenue Requirement	$ 102.290
13	RNS Revenues Received from NEPOOL	(89.156)
14	Schedule 1 Revenues Received	(3.600)
15	Estimated LNS Revenue Requirement	$ 9.534
16	Retail Load Ratio	97.00%
17	Estimated Retail LNS Revenue Requirement	$ 9.248
18		
19	**Total Estimated Transmission Costs**	$ 192.762
20	2005 Retail Net Transmission (Over)/Under	
21	Collection (Page 2, Line 30)	$ 14.987
22	Retail Transmission to be Collected	$ 207.749
23	Forecast 2006 Billed GWH	15,834.005
24	2006 Retail Transmission Rate	$ 0.01312

Boston Edison Company
2005 Retail Transmission Cost
$ in Millions

Line	Description	Tariff	Account	Dec-04	Actual Jan-05	Actual Feb-05	Actual Mar-05	Actual Apr-05	Actual May-05	Actual Jun-05	Actual Jul-05	Actual Aug-05	Estimate Sep-05	Estimate Oct-05	Estimate Nov-05	Estimate Dec-05	Total
	Regional Transmission Costs																
1	Retail RNS Cost	ISO Schedule 9	565590		$ 5.142	$ 4.788	$ 4.630	$ 4.674	$ 5.559	$ 5.911	$ 5.499	$ 6.880	$ 4.500	$ 4.500	$ 4.500	$ 4.500	$ 61.083
2	Regional Anciliary Services																
3	Retail Schedule & Dispatch Cost	ISO Schedule 1	561140		0.346	0.398	0.403	0.365	0.374	0.337	0.326	0.503	0.356	0.356	0.356	0.356	4.478
4	Retail Congestion Management Cost	Note A	565210		1.964	1.617	(0.322)	3.011	1.750	1.528	1.460	0.884	1.667	1.667	1.667	1.667	18.559
5	System Restoration & Planning Cost	ISO Schedule 16	565060		0.085	0.083	0.091	0.090	0.091	0.095	0.091	0.084	0.080	0.080	0.080	0.080	1.031
6	Load Dispatching (REMVEC)	MTDE No. 105	561110		0.023	0.023	0.023	0.023	0.023	0.023	0.024	0.024	0.023	0.023	0.023	0.023	0.279
7	NEPOOL Administration (Transmission)	MTDE No. 105	565190		0.007	(0.008)	0.008	0.008	0.009	0.009	0.009	0.009	0.005	0.005	0.005	0.005	0.071
8	VAR Support Cost	ISO Schedule 2			-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total Regional Transmission Costs				7.567	6.901	4.834	8.171	7.805	7.904	7.408	8.384	6.631	6.631	6.631	6.631	85.500
10	**Local Transmission Costs**																
11	Determination of Local Network Service (LNS) Costs	Note B															
12	Monthly Transmission Revenue Requirement				$ 6.794	$ 6.794	$ 6.794	$ 6.794	$ 6.794	$ 6.794	$ 6.794	$ 6.794	$ 6.794	$ 6.794	$ 6.794	$ 6.794	$ 81.524
13	RNS Revenues Received from NEPOOL		456690		(4.508)	(5.324)	(5.216)	(5.070)	(5.253)	(4.525)	(4.444)	(6.971)	(5.000)	(5.000)	(5.000)	(5.000)	(61.310)
14	Monthly Dispatch Center Revenue Requirement				0.337	0.337	0.337	0.337	0.337	0.337	0.337	0.337	0.337	0.337	0.337	0.337	4.046
15	Schedule 1 Revenues Received		456920		(0.346)	(0.411)	(0.403)	(0.368)	(0.390)	(0.334)	(0.327)	(0.390)	(0.258)	(0.258)	(0.258)	(0.258)	(4.000)
16	LNS Revenue Requirement				$ 2.277	$ 1.396	$ 1.511	$ 1.693	$ 1.489	$ 2.272	$ 2.359	$ (0.230)	$ 1.873	$ 1.873	$ 1.873	$ 1.873	$ 20.261
17	Retail Load Ratio				97.00%	97.00%	97.00%	97.00%	97.00%	97.00%	97.00%	97.00%	97.00%	97.00%	97.00%	97.00%	
18	Retail LNS Revenue Requirement				$ 2.209	$ 1.354	$ 1.466	$ 1.642	$ 1.444	$ 2.204	$ 2.289	$ (0.223)	$ 1.817	$ 1.817	$ 1.817	$ 1.817	$ 19.653
19																	
20	**Total Transmission Costs**				$ 9.776	$ 8.255	$ 6.300	$ 9.813	$ 9.249	$ 10.108	$ 9.697	$ 8.162	$ 8.449	$ 8.449	$ 8.449	$ 8.449	$ 105.153
21	**Transmission Revenues Detail**																
22	Residential		440140		$ 2.299	$ 2.298	$ 2.128	$ 1.924	$ 1.645	$ 1.866	$ 2.368	$ 2.567	$ 2.186	$ 1.888	$ 1.913	$ 2.234	$ 25.317
23	Commercial		442380		4.074	4.139	3.718	3.804	3.484	5.009	6.080	6.012	5.014	4.707	4.402	4.522	54.965
24	Industrial		442400		0.447	0.574	0.494	0.579	0.437	0.674	0.619	0.706	0.705	0.647	0.606	0.600	7.087
25	MWRA		442420		-	-	-	-	-	-	-	0.025	-	-	-	-	0.025
26	Street Lighting		444050		0.055	0.044	0.047	0.044	0.041	0.039	0.040	0.042	0.069	0.076	0.080	0.088	0.665
27	Transmission Revenues				$ 6.876	$ 7.055	$ 6.387	$ 6.351	$ 5.607	$ 7.589	$ 9.106	$ 9.352	$ 7.973	$ 7.319	$ 7.000	$ 7.444	$ 88.059
28	Retail Transmission Deferral (Over)/Under Collection				$ 2.901	$ 1.200	$ (0.088)	$ 3.461	$ 3.642	$ 2.519	$ 0.590	$ (1.190)	$ 0.475	$ 1.130	$ 1.449	$ 1.004	$ 17.094
29	Interest on Transmission Deferral Balance				(0.002)	0.002	0.003	0.007	0.014	0.020	0.023	0.023	0.022	0.024	0.026	0.029	0.191
30	Transmission Deferral (Over)/Under Ending Balance		182874	**$ (2.298)**	**$ 0.601**	**$ 1.803**	**$ 1.719**	**$ 5.187**	**$ 8.843**	**$ 11.383**	**$ 11.996**	**$ 10.829**	**$ 11.326**	**$ 12.479**	**$ 13.954**	**$ 14.987**	
31	Annual Interest Rate				2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	

Note A: ISO Schedule 19 (SCR) and Market Rule 1 (RMR)
Note B: Schedule 1 of ISO Schedule 21

Boston Edison Company
Monthly Standard Offer Deferral
$ in Millions

Line	Description	Dec-04	Actual Jan-05	Actual Feb-05	Total
1	Standard Offer Revenues [page 5, line 6]		$ (35.707)	$ (38.603)	$ (74.310)
2	Standard Offer Expense [minus line 1 minus prior mo. line 5]		35.707	38.603	74.310
3	Standard Offer Deferral (Over) / Under Recovery		-	-	-
4	Interest on SO Deferral Balance		-	-	-
5	SO Deferral (Over) / Under Ending Balance	**$ -**	**$ -**	**$ -**	
6	Standard Offer Expense Detail				
7	NUG Purchases [line 9 minus line 8]		$ (9.468)	$ 16.146	$ 6.678
8	Short Term Market Transactions [page 4, line 7]		46.353	23.410	69.763
9	Subtotal [line 12 + line 11]		36.885	39.556	76.441
10	Wholesale % [page 6, line 7]		3.30%	2.47%	
11	Wholesale Cost [line 12 * line 10]		1.178	0.953	2.132
12	Standard Offer Expense [line 2]		$ 35.707	$ 38.603	$ 74.310
	Annual Interest Rate		2.38%	2.38%	

Boston Edison Company
Monthly NUG Generation
GWH

Line	Description		Actual Jan-05	Actual Feb-05	Total
1	Masspower		65.226	74.928	140.154
2	MBTA Jets 1		0.026	-	0.026
3	MBTA Jets 2		0.027	-	0.027
4	NEA 1		111.879	101.285	213.164
5	NEA 2		69.613	63.020	132.633
6	Ocean State Power (Transcanada)		-	-	-
7	NUGs Generation		246.771	239.233	486.004
8	Less: Assumed Line Losses @	6.86%	(16.928)	(16.411)	(33.339)
9	Net GWH Delivered		229.843	222.822	452.665
10	Dist Co Settlement Price (line 11/line 9)		$ (0.04119)	$ 0.07246	
11	Cost of NUG Purchases (page 1, line 7)		$ (9.468)	$ 16.146	$ 6.678

Boston Edison Company
Total NUG Cost
$ in Millions

Line	Description	Actual Jan-05	Actual Feb-05	Total
1	Masspower	$ 5.418	$ 5.725	$ 11.143
2	MBTA Jets 1	(0.160)	0.059	(0.101)
3	MBTA Jets 2	0.241	0.227	0.468
4	NEA 1	7.108	(20.699)	(13.591)
5	NEA 2	7.286	11.595	18.881
6	Ocean State Power (Transcanada)	1.813	1.813	3.627
7	Hydro Quebec 1	0.104	0.141	0.245
8	Hydro Quebec 2	0.425	0.432	0.857
9	HQ Energy Line Usage	(0.146)	(0.033)	(0.180)
10	Connecticut Yankee	0.366	0.925	1.291
11	Mass Yankee	0.433	0.433	0.865
12	Total NUG Cost	$ 22.887	$ 0.617	$ 23.505

Boston Edison Company
Monthly Short Term Market Transactions
$ in Millions

Line	Description	Account	Actual Jan-05	Actual Feb-05	Total
	Cost				
1	Short Term SO - Sales	447640	$ 0.273	$ (29.295)	$ (29.022)
2	Short Term SO - Energy	555010	54.407	43.536	97.943
3	Short Term SO - Capacity	555020	-	-	-
4	ISO - NE	555030	(8.344)	9.152	0.808
5	ISO - NE (Admin)	555300	0.007	(0.008)	(0.001)
6	Miscellaneous Transmission	565260	0.010	0.025	0.035
7	Total ST Market Cost		$ 46.353	$ 23.410	$ 69.763

Boston Edison Company
Standard Offer Revenue
$ in Millions

Line	Description	Account	Actual Jan-05	Actual Feb-05	Total
1	Standard Offer Revenues				
2	Residential	440170	$ 15.675	$ 16.302	$ 31.977
3	Commercial	442450	17.302	19.292	36.594
4	Industrial	442460	2.086	2.443	4.528
5	Street Light	444070	0.645	0.566	1.211
6	Total Standard Offer Revenues		$ 35.707	$ 38.603	$ 74.310
7	Standard Offer GWH Sales		550.736	579.674	1,130.410

Boston Edison Company
Monthly Wholesale GWH Sales, Wholesale Sales as Percentage of Sales

Line	Wholesale Customer	Actual Jan-05	Actual Feb-05	Total
1	Braintree	-	-	-
2	MassPort	18.809	14.664	33.473
3	Other	-	-	-
4	Total Wholesale Sales	18.809	14.664	33.473
5	Retail Sales - SO	550.736	579.674	1,130.410
6	Total Sales (Whsle + SO)	569.545	594.338	1,163.883
7	Wholesale % (Line 4 / line 6)	3.30%	2.47%	

Boston Edison Company
Monthly Default Service Deferral
$ in Millions

Line	Description	Account	Dec-04	Actual Jan-05	Actual Feb-05	Actual Mar-05	Actual Apr-05	Actual May-05	Actual Jun-05	Actual Jul-05	Actual Aug-05	Forecast Sep-05	Forecast Oct-05	Forecast Nov-05	Forecast Dec-05	Total
1	Default Service Revenues [line 13]			$ (29.851)	$ (33.045)	$ (49.424)	$ (61.218)	$ (52.431)	$ (62.295)	$ (73.731)	$ (80.253)	$ (59.792)	$ (59.545)	$ (58.279)	$ (64.983)	$ (684.847)
2	Default Service Adjustment Revenues [line 21]			(0.540)	-	-	-	-	-	-	-	-	-	-	-	(0.540)
3	Default Service Expense			37.472	28.951	67.521	48.391	50.297	62.741	86.231	78.534	55.180	54.970	57.129	69.533	696.950
4	Default Service Deferral (Over) / Under Recovery			7.081	(4.094)	18.097	(12.827)	(2.134)	0.446	12.500	(1.719)	(4.612)	(4.575)	(1.150)	4.550	11.563
5	Interest on Default Service Deferral Balance			0.003	0.006	0.020	0.026	0.011	0.009	0.022	0.033	0.026	0.017	0.012	0.015	0.200
6	Default Service (Over) / Under Ending Balance		**$ (1.815)**	**$ 5.269**	**$ 1.181**	**$ 19.298**	**$ 6.497**	**$ 4.374**	**$ 4.829**	**$ 17.351**	**$ 15.665**	**$ 11.079**	**$ 6.521**	**$ 5.383**	**$ 9.948**	
7	Default Service Revenues Detail															
8	Residential	440180		$ 10.174	$ 11.844	$ 19.099	$ 25.145	$ 21.559	$ 24.458	$ 31.428	$ 34.456	$ 28.470	$ 24.506	$ 24.828	$ 29.006	$ 284.973
9	Commercial	442480		18.357	19.445	27.450	32.994	28.086	34.518	38.725	41.927	28.528	32.179	30.663	32.987	365.859
10	Industrial	442490		1.187	1.640	2.516	2.852	2.596	3.136	3.359	3.620	2.517	2.425	2.326	2.446	30.620
11	MWRA	442472		-	-	-	-	-	-	-	-	-	-	-	-	-
12	Street Light	444100		0.133	0.116	0.359	0.227	0.190	0.183	0.219	0.250	0.277	0.435	0.462	0.544	3.395
13	Total Default Service Revenues			$ 29.851	$ 33.045	$ 49.424	$ 61.218	$ 52.431	$ 62.295	$ 73.731	$ 80.253	$ 59.792	$ 59.545	$ 58.279	$ 64.983	$ 684.847
14	Default Service GWH Sales			415.407	412.048	631.692	816.164	717.293	849.447	969.436	1,021.658	774.660	721.300	700.040	764.180	8,793.325
15	Default Service Adjustment Revenues Detail															
16	Residential	440175		$ 0.164	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.164
17	Commercial	442455		0.330	-	-	-	-	-	-	-	-	-	-	-	0.330
18	Industrial	442465		0.036	-	-	-	-	-	-	-	-	-	-	-	0.036
19	MWRA	442475		0.004	-	-	-	-	-	-	-	-	-	-	-	0.004
20	Street Light	444075		0.006	-	-	-	-	-	-	-	-	-	-	-	0.006
21	Total Default Service Adjustment Revenues			$ 0.540	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.540
22	Total GWH Sales			1,289.036	1,391.071	1,295.846	1,224.171	1,059.367	1,280.537	1,407.096	1,495.459	1,385.810	1,272.310	1,218.040	1,293.910	15,612.653
	Annual Interest Rate			2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	

Boston Edison Company
Monthly Default Service Deferral
$ in Millions

Line	Description	Dec-04	Forecast Jan-06	Forecast Feb-06	Forecast Mar-06	Forecast Apr-06	Forecast May-06	Forecast Jun-06	Forecast Jul-06	Forecast Aug-06	Forecast Sep-06	Forecast Oct-06	Forecast Nov-06	Forecast Dec-06	Total
1	Default Service Revenues [line 10]		$ (147.298)	$ (179.088)	$ (146.692)	$ (111.004)	$ (92.713)	$ (92.883)	$ (121.952)	$ (142.324)	$ (125.851)	$ (113.499)	$ (120.703)	$ (134.505)	$ (1,528.513)
2	Default Service Adjustment Revenues [line 14]		(0.465)	(0.879)	(0.864)	(0.818)	(0.751)	(0.803)	(0.903)	(0.950)	(0.924)	(0.836)	(0.786)	(0.862)	(9.841)
3	Default Service Expense		190.870	166.529	116.805	103.868	89.293	98.963	143.854	148.012	102.394	123.501	123.668	139.957	1,547.715
4	Default Service Deferral (Over) / Under Recovery		43.107	(13.438)	(30.751)	(7.955)	(4.171)	5.277	20.999	4.738	(24.380)	9.166	2.179	4.590	9.362
5	Interest on Default Service Deferral Balance		0.062	0.092	0.048	0.010	(0.002)	(0.001)	0.025	0.051	0.031	0.016	0.028	0.034	0.394
6	Default Service (Over) / Under Ending Balance	**$ 9.948**	**$ 53.118**	**$ 39.771**	**$ 9.069**	**$ 1.124**	**$ (3.049)**	**$ 2.227**	**$ 23.251**	**$ 28.040**	**$ 3.690**	**$ 12.873**	**$ 15.080**	**$ 19.704**	
7	Default Service Revenues Detail														
8	Default Service GWH Sales		972.933	933.343	906.785	849.906	772.348	825.513	941.789	997.491	961.880	860.030	817.432	913.192	10,752.642
9	Default Service Price		$ 0.15140	$ 0.19188	$ 0.16177	$ 0.13061	$ 0.12004	$ 0.11252	$ 0.12949	$ 0.14268	$ 0.13084	$ 0.13197	$ 0.14766	$ 0.14729	
10	Default Service Revenues		$ 147.298	$ 179.088	$ 146.692	$ 111.004	$ 92.713	$ 92.883	$ 121.952	$ 142.324	$ 125.851	$ 113.499	$ 120.703	$ 134.505	$ 1,528.513
11	Default Service Adjustment Revenues Detail														
12	Total GWH Sales		1,408.042	1,351.954	1,329.678	1,258.784	1,154.797	1,235.038	1,389.916	1,462.089	1,421.456	1,286.295	1,209.341	1,326.615	15,834.005
13	Default Service Adjustment Price		$ 0.00033	$ 0.00065	$ 0.00065	$ 0.00065	$ 0.00065	$ 0.00065	$ 0.00065	$ 0.00065	$ 0.00065	$ 0.00065	$ 0.00065	$ 0.00065	
14	Default Service Adjustment Revenues		$ 0.465	$ 0.879	$ 0.864	$ 0.818	$ 0.751	$ 0.803	$ 0.903	$ 0.950	$ 0.924	$ 0.836	$ 0.786	$ 0.862	$ 9.841
	Annual Interest Rate		2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	2.38%	

BOSTON EDISON COMPANY
d/b/a NSTAR ELECTRIC

Direct Testimony of Henry C. LaMontagne

Exhibit BEC-HCL

D.T.E. 05-88

Q. Please state your name and business address.

A. My name is Henry C. LaMontagne. My business address is One NSTAR Way, Westwood, Massachusetts 02090.

Q. By whom are you employed and in what capacity?

A. I am Director of Regulatory Policy and Rates for the regulated operating companies of NSTAR. In this capacity, I am responsible for pricing and rate design activities for Boston Edison Company ("Boston Edison" or the "Company"), Cambridge Electric Light Company ("Cambridge"), Commonwealth Electric Company ("Commonwealth") (collectively, "NSTAR Electric" or the "Companies") and NSTAR Gas Company.

Q. Please describe your education and professional background.

A. I graduated from the University of Massachusetts - Dartmouth in 1968 with a Bachelor of Science degree in Electrical Engineering. Upon graduation, I served two years of military duty, after which I joined the Engineering Department of COM/Energy Services Company ("COM/Energy") in October 1970. In March 1973, I became a Rate Analyst with the Rate Department of COM/Energy where my primary responsibilities were to assist in the formulation and administration of gas and electric tariffs and special contracts for the operating subsidiaries of the Commonwealth Energy System. Since then, I have held various positions in the Rate

Department progressing to Manager – Rate Design in March 1987. I held that position in the Commonwealth Energy System until its merger with BEC Energy was consummated in August 1999, whereupon I was named to my present position.

Q. Please describe your present responsibilities.

A. As Director of Regulatory Policy and Rates, I am responsible for directing the preparation and design of rate schedules and the pricing of special contracts for NSTAR. In addition, I am responsible for directing the preparation of embedded and marginal cost allocation studies and other special cost studies as required to support the pricing and rate design function.

Q. Have you previously testified in any formal hearings before regulatory bodies?

A. Yes, I have presented testimony before the Department of Telecommunications and Energy (the "Department") and the Federal Energy Regulatory Commission ("FERC") on numerous occasions. I have most recently presented testimony before the Department on behalf of Boston Edison, Commonwealth and Cambridge in D.T.E. 03-121, a standby rate proceeding. I have also presented testimony before the Department on behalf of Boston Edison in D.T.E. 04-113, its most recent Transition Charge Reconciliation proceeding. I have also presented testimony on behalf of Cambridge and Commonwealth in their most recent Transition Charge Reconciliation proceeding, D.T.E. 03-114. Previously, I have presented testimony for Cambridge, Commonwealth and Canal Electric Company in their comprehensive electric restructuring plan (the "Restructuring Plan") proceeding, D.P.U./D.T.E. 97-

111 (1998) and their divestiture proceeding, D.T.E. 98-78/83 (1998). Also previously, I have presented testimony on behalf of Cambridge, Commonwealth and Commonwealth Gas Company in general rate proceedings before the Department in Cambridge Electric Light Company, D.P.U. 94/101/95-36 (1995), Commonwealth Gas Company, D.P.U. 95-102 (1995), and Commonwealth Electric Company, D.P.U. 90-331 (1990). In addition, I have presented testimony before the FERC concerning transmission service to the Town of Belmont, in FERC Docket Nos. ER94-1409 and EL94-88.

Q. What is the purpose of your testimony?

A. My testimony will describe the proposed changes to rates resulting from reconciling Boston Edison's Transition Charge, Transmission Charge and Default Service rates for the year 2005. My testimony will describe how the new rates will be implemented and what their impact will be on customers' bills.

Q. When will the proposed rate changes take effect?

A. The new charges are proposed to become effective on January 1, 2006.

Q. What exhibits are you sponsoring in your testimony?

A. I am sponsoring eight exhibits as well as this testimony, Exhibit BEC-HCL. Exhibit BEC-HCL-1 is the redlined versions of the proposed tariffs. Exhibit BEC-HCL-2 sets forth the rate design models used to develop the proposed rates. Exhibits BEC-HCL-3 and BEC-HCL-5 set forth the pricing models supporting current prices for Rate S-1 and S-3, respectively. Exhibits BEC-HCL-4 and BEC-HCL-6 set forth the pricing models supporting proposed prices for Rate S-1 and S-3, respectively. Exhibit BEC-HCL-7 sets forth the development of the Transition Rate Adjustments for year 2004. Finally, Exhibit BEC-HCL-8 sets forth typical bill calculations that compare current rates to proposed rates.

Q. What are the changes to rates that Boston Edison is proposing?

A. Boston Edison is proposing, in this filing, changes to its Transition Charge, the Transition Adjustment Charge, the Transmission Charge and the Default Service Adjustment. The annual change in the Pension Adjustment Factor is being proposed in submissions filed in D.T.E. 05-90. The proposed rates also reflect the Basic Service rates recently approved by the Department for effect January 1, 2006. The Changes to the Transition Charge and Default Service Adjustment Charge are addressed in the testimony of Christine L. Vaughan, Exhibit BEC-CLV. The changes to the transmission rates reflect the Company's latest calculation of annual prices under its FERC Transmission Tariff as described in Exhibit BEC-CLV.

Q. Have you provided proposed tariffs that reflect the rate changes described above?

A. Yes, the proposed tariffs have been filed with the cover letter to this filing. Exhibit BEC-HCL-1 is the redlined version of the companies' proposed rate schedules.

Q. Have you provided a schedule showing the proposed changes to current rates?

A. Yes. Exhibit BEC-HCL-2 sets forth the proposed changes to current rates for each rate class and calculates the percentage change for the major price components for each rate schedule.

Q. What changes to Boston Edison's Transition Charges for 2006 are you proposing as a result of reconciling 2005?

A. In her testimony, Ms. Vaughan supports a Transition Charge for the year 2006 of 1.916 cents per kilowatt-hour ("kWh") for Boston Edison. This charge compares to the current Transition Charge for the second half of 2005 of 1.634 cents per kWh. For reference, the initial Transition Charge included in the Restructuring Settlement was 3.510 cents per kWh, and the amount originally scheduled in the Restructuring Settlement for 2006 was 2.43 cents per kWh.

Q. How have you reflected the change to the Transition Charges in Boston Edison's rates?

A. First, I assign the same average Transition Charge rate to each rate class, with the exception of Rate WR, which I will discuss separately. To this average Transition Charge, I add a class-specific Transition Charge Adjustment, pursuant to Section 2.4 of the terms of the settlement agreement entered into between and the Attorney General in D.T.E. 00-82, approved by the Department on November 16, 2001. The methodology for the calculation of the Transition Charge Adjustment for each class for the year 2004 is set forth in Exhibit BEC-HCL-7. The purpose of the adjustment is to ensure that the reconciliation of the Transition Charge maintains a uniform recovery of the average transition charge from each customer class.

Q. How have you reflected the Transition Rate Adjustment for Rate T-1?

A. In the rates implemented for year 2002, the Transition Charge Adjustment calculated for Rate T-1 was 3.072 cents/kWh. This represented the adjustment for the years 1998 through 2000. This amount of adjustment was too great to implement in one year while maintaining the mandated 15 percent rate reduction for this rate class. As a result, Boston Edison implemented only a portion of this total adjustment in its rates for 2003, 2004 and 2005. Because rates are no longer subject to the rate cap, the Company has added the remainder of the unrecovered initial adjustment (i.e., 3.072-0.767-0.767-0.263-0.180=1.095) to the 2006 transition rate adjustment (i.e., 0.008 + 1.095 = 1.103).

Q. Please explain how the Transition Charge has been set for Boston Edison's Rate WR.

A. Unlike previous years, where the WR rate class was charged a single "Delivery Services" charge without a separately stated Transition Charge, Transmission Charge or Distribution Charge, Rate WR is now fully unbundled as approved by the Department for the rate effective May 1, 2005. As a result, the provisions of the Settlement Agreement (approved by the Department in D.T.E 01-108 on May 31, 2002) dealing with transition charges for the period 2005 to 2010 apply. The revised rate includes a Transition Cost Adjustment that is calculated in accordance with the provisions of the Settlement Agreement. The calculation of the Rate WR Transition Cost Adjustment is set forth in Exhibit BEC-HCL-7A.

Q. What rate changes are proposed for Transmission rates?

A. The proposed average transmission rate reflects an increase of 0.732 cents per kWh resulting in a total average rate of 1.312 cents per kWh. The current average transmission rate is 0.580 cents per kWh. The current average transmission charges for individual rate schedules are adjusted to reflect the ratio of the proposed transmission rate to the current transmission rate (i.e., 1.312/0.580= 2.262). Ms. Vaughan describes the development of the revised average Transmission rate in her testimony.

Q. How have you implemented the Pension Adjustment Factor?

A. I implemented the Pension Adjustment Factor of 0.030 cents per kWh as a uniform charge per kWh for each rate class. For billing purposes the Pension Adjustment Factor is included with the Company's distribution charges.

Q. Are you proposing changes to distribution rates?

A. No. Current distribution rates are remaining unchanged.

Q. Have you provided typical bill calculations that compare proposed rates with currently effective rates?

A. Yes. Exhibit BEC-HCL-8 sets forth Boston Edison's typical bill comparisons.

Q. Does this conclude your testimony?

A. Yes, it does.